BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.

Rulemaking 15-02-020
(Filed February 26, 2015)

JOINT PROPOSAL OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E)

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JOINT PROPOSAL OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E)

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I.

INTRODUCTION AND EXECUTIVE SUMMARY

Pursuant to Ordering Paragraph 4 of the Administrative Law Judge's Ruling Accepting into the Record Energy Division Staff Paper on Least-Cost Best-Fit ("LCBF") Reform for Renewables Portfolio Standard Procurement and Requesting Comment, dated June 22, 2016 (the "Ruling"), Southern California Edison ("SCE"), San Diego Gas and Electric Company ("SDG&E") and Pacific Gas and Electric Company ("PG&E") (hereinafter collectively referred to as the "Investor Owned Utilities" or "IOUs") respectfully file this Joint Proposal.

A.   Background

The Ruling directed the IOUs to prepare a Joint Proposal—as described in Question 1 of Attachment A to the Ruling—and file and serve it no later than September 8, 2016. The Joint Proposal is to include a standardized methodology and set of inputs and assumptions for estimating future capacity prices.

Question 1. Similar to the proposals being developed for a standardized ELCC methodology, utilities should develop a joint proposal for a standardized methodology and set of inputs and assumptions for estimating future capacity prices. The joint proposal should include

a. standardized inputs and assumptions;
b. draft capacity prices; and
c. a benchmarking report.

The joint proposal should include all the requested information listed under question 2.[1] The benchmarking report should compare the draft capacity values with those in the RPS Calculator and any other useful public source of capacity values, along with an explanation of any major deviations. Energy Division staff will compare the public values developed by utilities with the individual utilities' own values to assess whether they are reasonably similar. Utilities should contact Energy Division staff with any clarifying questions about the details of the information requested.

B.   Purpose

The IOUs understand that this Joint Proposal is to create publicly-available forward capacity price curves as a benchmark for evaluations and rankings of competitive offers using each IOU's own, confidential, LCBF methodologies.

An example of such benchmarking occurred in the IOUs' 2014 energy storage solicitations. Each IOUs' application for approval of agreements provided the benchmarking

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[1]   Question 2 of Attachment A to the Ruling asks for "Assumptions and calculations for short and long term avoided cost, including derivation of forward capacity price curves for both system and local capacity; detailed description of any modeling tools used; and derivation of resource balance table. Include all demand and supply side assumptions."

results.[2] Within the energy storage proceeding, a Consistent Evaluation Protocol ("CEP") was developed to define the methodology for calculating these benchmarking results.[3]

The IOUs believe that taking an approach similar to the CEP approach utilized in the energy storage context would maximize benefits and minimize the risks to customers. This approach would allow the IOUs to continue to use their confidential capacity price curves and models in their individual LCBF evaluation processes for purposes of resource evaluation and ranking. This is necessary because each IOU has unique portfolio needs, inputs, and assumptions that will inevitably differ across entities, and the current practice allows these differences to be recognized. To the extent the Commission finds that a benchmarking methodology using publicly-available capacity prices would be useful in evaluating the results of the IOUs' respective LCBF evaluations, the IOUs recommend developing that benchmarking methodology in a manner similar to the CEP process used in the energy storage context described above.

The IOUs also point out that although a Joint Proposal for a standardized methodology and set of inputs and assumptions for estimating future capacity prices is being proposed here for

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[2] *See*, e.g., Application ("A.") 15-12-004, Application of Pacific Gas and Electric Company for Approval of Agreements Resulting From Its 2014-2015 Energy Storage Solicitation and Related Cost Recovery, Attachment B of Chapter 4 of prepared testimony, filed December 1, 2015; A.15-12-003, Application of Southern California Edison Company (U338E) for Approval of Contracts Resulting From Its 2014 Energy Storage Request for Offers (ES RFO), Appendix E of prepared testimony, filed December 1, 2015.

[3] Decision 13-10-040, at 63, Decision Adopting Energy Storage Procurement Framework and Design Program, requiring the IOUs to confer with Energy Division Staff to develop a CEP to be used for benchmarking and general reporting purposes. Accordingly, the IOUs and Energy Division conferred for over a year to create the CEP. In Appendix A of that Decision, Section (3)(d), the CEP is described further as the follows:

> *An evaluation protocol consistent across the IOUs that includes a consistent set of assumptions and methods for valuing storage benefits, such as market services and avoided costs, and estimating project costs that allow adjustments for utility specific factors (such as location, portfolio, cost of capital, etc.) and -utility specific- modeling tools based outputs affecting valuation as appropriate to provide a consistent basis for comparison across utilities, bids, and use cases.*

benchmarking purposes, the capacity values that result from this proposal would be system capacity values.

C.   **Benefits and Risks**

As parties pointed out in their opening comments on the Energy Division Staff Paper on LCBF Reform, there are potential benefits to providing information to parties on how the utilities value capacity in their solicitations.[4] Some transparency may help bidders to make important decisions on the types of projects that can provide the most value to the system and to customers. However, there would be significant risks to customers of using public forward capacity price curves to evaluate and rank offers in the LCBF process. Confidential prices protect the competitiveness of solicitation results, and by extension, protect customers from overpaying for procurement. If components of contract value, such as capacity, are set administratively, bidders might be tempted to submit offers at or very close to those administratively set values, rather than submit their lowest-priced offer, negating a competitive marketplace for RPS procurement.[5]

Furthermore, any requirement to mandate the use of public capacity prices in the actual LCBF evaluations would likely conflict with the confidentiality matrix established by the Commission in D.06-06-066, which specifies, among other things, that the details of the scoring and evaluation of bids should remain confidential for three years after winning bidders are

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[4] *See* Opening Comments of CalWEA p. 3-4; GPI p. 5; ORA p. 2-3

[5] An example in which sellers did get to see the avoided capacity cost benefit for the product they were selling is demand response. In D.12-04-045, the Commission directed PG&E to solicit new agreements for its 2013-2014 Aggregator Managed Portfolio demand response contracts. In doing so, the Commission found that a Total Resource Cost ("TRC") benefit-cost ratio of 0.90 (i.e., costs exceed benefits by eleven percent) would be deemed cost-effective. (D.12-04-045, p. 76 and Ordering Paragraph 15). Likewise, the spreadsheet used to calculate that benefit-cost ratio was made publicly available. PG&E received offers from five sellers with an aggregate TRC of 0.94, barely different from the Commission's announced threshold. Had the Commission announced it would set the cost-effectiveness bar higher, e.g., 0.95 or even 1.0, PG&E might have received more cost-effective offers. Providing exact valuation metrics in advance of solicitations can harm customers by encouraging market participants to tailor their offers to maximize revenues, as opposed to providing competitive, lower-priced offers.

selected.[6] The Commission developed this approach to confidentiality to balance the potential

benefits of public disclosure while protecting against the risks. The Commission, with

considerable input from stakeholders, has already weighed the considerations of making this

information public, and chose to protect the confidentiality of LCBF components during the

period when its disclosure could lead to market manipulation. As the Commission specifically

stated in D.06.06.066, "confidentiality protections are essential to avoid a repetition of electricity

market manipulation."[7] Most importantly, these protections are in place to protect customers and

provide safeguards to prevent them from being negatively impacted by any potential gaming or

market manipulation.

II.

JOINT PROPOSAL FOR A STANDARDIZED METHODOLOGY AND SET OF INPUTS AND ASSUMPTIONS FOR ESTIMATING FUTURE CAPACITY PRICES

The IOUs propose the following methodology for creating benchmarking values for

future capacity prices on an annual basis. The benchmarking values for the capacity price

forecast consist of a forecast of short run capacity prices and long run capacity prices with the

transition between the short and long run marked by the Resource Balance Year ("RBY"), i.e.

the year in which system demand exceeds system capacity. This methodology can be

implemented as described below utilizing the most recent avoided cost model developed by the

Commission's consultant, E3,[8] for demand-side management ("DSM") program cost-

effectiveness evaluations.[9]

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[6]   D.06-06-066, Appendix 1, pp. 17-18 (Lines VII and VIII).
[7]   D.06-06-066, p. 4.
[8]   E3's full name is Energy + Environmental Economics.
[9]   E3's public avoided cost model, created for Energy Division, was the source of these public prices
      and can be found at the following url: https://ethree.com/public_projects/cpuc5.php.

A.   Estimating Future Capacity Prices

A capacity price curve is a forecast of the expected cost of alternative procurement of capacity at a certain point in the future. A capacity price curve is a combination of short-run and long-run avoided capacity price forecasts based on the RBY.[10] Short-run capacity costs are determined for years prior to the RBY. Long-run capacity costs are determined for years on and following the RBY. Prior to the RBY, short-run capacity prices transition up to the long-run capacity prices that begin in the RBY.

B.   Source of Public Short-run Capacity Prices

A public forecast of short-run capacity prices already exists in the Commission's Resource Adequacy ("RA") Report.[11] The most recent RA Report is the 2013-14 RA report published August 2015. The short-run capacity price forecast—i.e., the weighted average RA prices by year—is found in Table 10 of the 2013-14 RA Report. For convenience, those short-run capacity prices are reproduced in the following Table II-1.

Table II-1

Short-run Capacity Prices from Table 10 of 2013-14 RA Report

Year	Weighted Average Monthly RA Price times twelve Months	Forecast Annual Short-run Capacity Prices
2013	$3.45/kW-month x 12 months	$41.40/kW-year
2014	$3.41/kW-month x 12 months	$40.92/kW-year
2015	$3.12/kW-month x 12 months	$37.44/kW-year
2016	$2.70/kW-month x 12 months	$32.40/kW-year
2017	$3.16/kW-month x 12 months	$37.92/kW-year

There are a variety of methods that can be used to create a transition from short-run capacity prices prior to the RBY to long-run capacity prices beginning in the RBY. The IOUs propose using short-run capacity prices from the most recent RA Report and performing a linear

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[10]   RBY is the year in which there are insufficient existing resources to meet system capacity needs.
[11]   http://www.cpuc.ca.gov/ra/.

interpolation between the current years forecast price up to the long-run capacity price beginning in the RBY.[12] The E3 avoided cost model, described below, can be used to develop a complete capacity price curve including the linear interpolation.

C.   Determination of the Resource Balance Year ("RBY")

The RBY for the relevant area of this analysis, i.e., the California Independent System Operator ("CAISO") balancing authority area, is calculated using a stacking metric that compares a forecast of annual load (*i.e.,* demand) to a forecast of annual available generation capacity (*i.e.*, supply). The RBY is the year in which available generation capacity falls below 115% of the load. The 115% represents a planning reserve margin ("PRM") that is used to determine if the CAISO has enough generation capacity in reserve to reliably serve load. If the supply falls below 115% of load then there may be a reliability concern requiring a Resource Balance Need ("RBN") (*i.e.,* new capacity). The RBN should be calculated every year until a point in time occurs where the RBN is positive. Once the RBN is a positive value, the corresponding year would be the RBY. The equations are listed below.

> *Resource Balance Need = (Load * 1.15) – Available Capacity*
> *Where:*
> *Load =   Coincident CAISO Peak – Non-Dispatchable Demand Response –*
> *   Energy Efficiency – Behind the meter Resources*
> *Available Capacity[13]=Existing Generation + Generation Additions – Generation*
> *   Retirements*

Although not the only source, the most comprehensive data source for developing the RBY in the CAISO area is the Long Term Procurement Plan ("LTPP") scenario tool developed by the Energy Division. The Commission's LTPP website contains this scenario tool, including
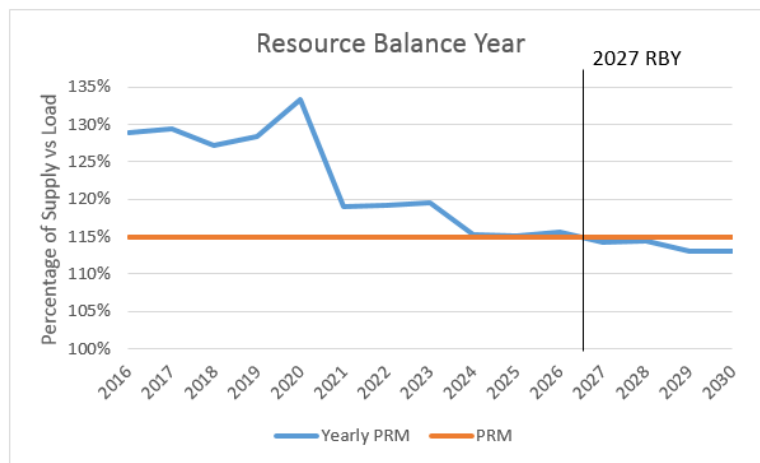
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[12]   As with the linear interpolation approach described here, there are also various approaches that could be used to determine how much capacity will be reliably available when needed. The LTPP scenario tool discussed below in the section describing how the RBY is determined utilizing the CPUC's LTPP scenario tool for 2016. This approach has drawbacks because there are many potential scenarios and generic assumptions that could change the RBY calculation.

[13]   Existing generation is generation available today while generation additions are known future contracts or known generic additions from regulatory proceedings such as RPS.

assumptions.[14] The 2016 LTPP scenario tool documentation already incorporates the appropriate assumptions and includes the RBY calculation for the different LTPP scenarios. Figure II-1 is an illustrative example of the results for one scenario. Table II-2 shows example inputs for the 2016 LTPP scenario planning tool. Running the scenario tool for the 2016 LTPP with these inputs results in an RBY of 2027. Note that this scenario uses a "1 in 10" (extreme weather) coincident peak. If a different weather condition were assumed, for example a "1 in 2" (expected) coincident peak, the RBY would occur in a later year.

Figure II-1
Illustrative Resource Balance Year Estimate Using 2016 LTPP Scenario Tool Ver. 1.2

Source: Scenario Source: Tool2016v1.2xlsx, http://www.cpuc.ca/General.aspx?id=11681

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[14] General LTPP webpage: http://www.cpuc.ca.gov/LTPP/ and Scenario Tool webpage: http://www.cpuc.ca.gov/General.aspx?id=11681.

Table II-2

Example Inputs for 2016 LTPP Scenario Planning Tool Ver. 1.2

Scenarios used in CPUC LTPP Scenario Tool	
Load	
Managed Demand Net Load	Mid (1-in-10) CAISO Coincident peak - High AAEE
BTM resources modeled as Supply	
1: Inc. Small PV	None
2: Inc. Demand-side CHP	None
Supply	
4: RPS Resources (Including Additions)	50% by 2030 portfolio (fully-deliverable w/ Mid-AAEE
Authorized Procurement	D.13-02-015 & D.14-03-004
6: Imports	ISO available import
7: Inc. Supply-side CHP	None
8: Dispatchable DR	Default
9: Energy Storage Target	Low
10: Energy Storage Other	None
Retirements	
OTC Nuclear	DCPP
Hydro + Pump	Low
Other (non-OTC thermal/cogen/other)	Mid

Source: Scenario Tool 2016 v1.2.xlsx, http://www.cpuc.ca.gov/General.aspx?id=11681
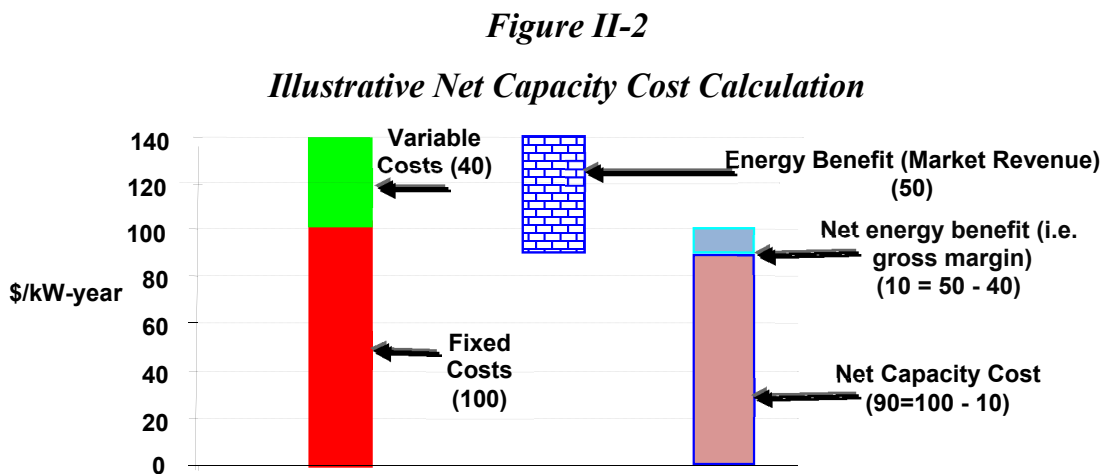
D. Source of Public Long Run Capacity Prices

The long run capacity price is also referred to as the net Cost of New Entry ("CONE").

Net CONE represents the typical cost to the utility of building a new combustion turbine

generation facility ("CT Proxy") minus the energy revenues earned for dispatching in the energy

markets.[15] The initial, all-in construction cost of the CT Proxy includes Allowance for Funds

Used during Construction. The annual revenue requirements associated with this construction

cost are projected in constant dollars over the economic life of the plant and include Property tax

and Fixed Operations and Maintenance, Administrative and General Costs and Insurance. The

annual revenue requirements are levelized using a Real Discount Rate. Estimated constant dollar

energy rents (i.e., the Energy Related Capital Cost) for the economic life of the plant are

levelized using the Real Discount Rate and then subtracted from the levelized annual revenue

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[15] This is also called energy gross margin. Energy gross margin is the expected market revenue of a resource net of its variable cost. A generation resource is assumed to earn net energy market revenues (i.e., energy market revenues less variable costs) only when the electric energy price is higher than the variable costs.

requirement to obtain the net CONE value, or net long-run capacity cost. Figure II-2 shows an illustrative example of such a net long-run capacity cost calculation.

Figure II-2

Illustrative Net Capacity Cost Calculation

E3's avoided cost model, developed for DSM programs, is a public tool that produces a net CONE estimate as a forecast of long-run capacity prices. The latest, official, avoided cost model on E3's website is for the Self-generation Incentive Program ("SGIP").[16],[17] The avoided cost model estimates annualized fixed and variable operating costs of a CT Proxy and removes energy rents that represent Real Time Dispatch and Ancillary Services year by year, which are then adjusted for temperature. The result is a net CONE estimate for each year that becomes a public forecast of long-run capacity prices.

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[16] https://ethree.com/public_projects/cpucSGIP.php.
[17] E3 is preparing an update (http://www.cpuc.ca.gov/General.aspx?id=10710) of its avoided cost model for the Commission in the Integrated Distributed Energy Resources ("IDER") proceeding, but it is not yet finalized. Resolution E-4801 is currently scheduled to appear on the September 29, 2016, Commission Meeting Agenda.

III.

DRAFT CAPACITY PRICES

A.   Developing the Capacity Price Forecast Using the E3 Avoided Cost Model

The following process can be used to develop the capacity price curve using the above methodology and the E3 avoided cost model:

1. Download the Commission's latest version of the E3 avoided cost model. In this case, the version from the SGIP proceeding is being used.

2. In the "Inputs" tab of the model, enter in the RBY calculated from the LTPP Scenario Tool as described above. Using the inputs in version 1.2 of the scenario tool, the RBY is 2027.

3. In the "Market Dynamics" tab of the model, in cell C10, enter the latest year's average RA price from the CPUC RA Report. In this case, $32.40/kW-year was used for 2016. Also, enter the year of the RA price in cell C11. In this example, 2016, the current year, was used.

4. The capacity price curve—with short-run capacity costs transitioning to long-run capacity costs—forecast can be found in row 194 entitled, "Capacity Value" (Note: row 195 adjusts those values for temperature-related inefficiency and row 196 adjusts those values for system losses.)

Thus, the RBY is entered into the avoided cost model to create a capacity curve that forecasts the short run and long run capacity prices with a linear interpolation between the short run and long run. Figure III-3 and the accompanying Table III-3 provides the indicative capacity price curve produced from the E3 Avoided Cost model from SGIP 2015. For this example, more recent RA prices as well as the RBY determined from the LTPP Scenario model described above has been utilized. The description of the process for developing the curve is provided in the next section.

The preceding process leads to the following estimated capacity price forecast.

Figure III-3

Illustrative Capacity Price Curve Developed using the E3 Avoided Cost Model
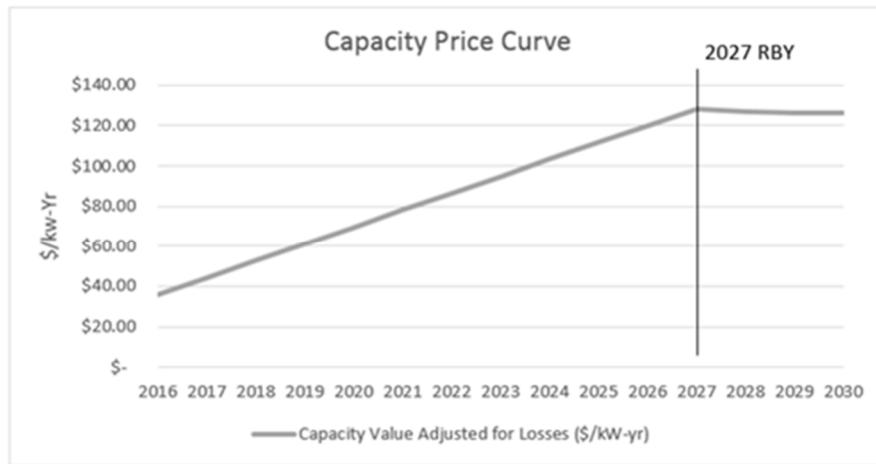
Source: E3_NEM_Avoided_Cost_Model_SGIP_Update_20150521.xlsm, with inputs and process in Section E, https://www.ethree.com/public_projects/cpucSGIP.php

Table III-3

Illustrative Capacity Price Curve Using Joint IOU Proposal

Year	Capacity Prices ($/kW-Year)
2016	$ 35.92
2017	$ 44.33
2018	$ 52.74
2019	$ 61.16
2020	$ 69.57
2021	$ 77.99
2022	$ 86.40
2023	$ 94.81
2024	$ 103.23
2025	$ 111.64
2026	$ 120.05
2027	$ 128.47
2028	$ 126.68
2029	$ 126.15
2030	$ 126.40

As already stated above, the illustrative capacity curve in Figure III-3 is the result of the specific inputs, assumptions, and methodology chosen by the IOUs for this Joint IOU Proposal. This methodology and these results represent a reasonable way to calculate a long run capacity price curve, but it is by no means the only way to calculate a capacity price curve. These results are not intended to be indicative of the capacity price curves that the utilities use for their own LCBF valuations, nor are they intended to forecast the expected price of system RA in CAISO. Rather, the purpose of this exercise is to provide parties with an example of how a capacity curve might be calculated, and to help them understand how specific inputs impact the final price curve.

IV.

BENCHMARKING

As requested in the Ruling, Table IV-4 presents a benchmarking of the draft capacity values from this Joint IOU Proposal against the capacity prices provided in the RPS Calculator. However, this comparison is complicated because the forecast capacity values in this Joint Proposal and the RPS Calculator deviate because different methodologies are utilized in the calculation. The RPS Calculator forecasts either a single short-run avoided capacity value, e.g., $33/kW-year, or a single long-run avoided capacity value, depending if the generation supply in the RPS Calculator exceeds the planning reserve margin or not. The Joint Proposal includes both short-run and long-run capacity prices with a linear interpolation between short run and long run prices that escalates the short-run capacity prices until the RBY is reached and the long-run capacity prices commence.

Table IV-4

Capacity Price Benchmark Against RPS Calculator

Year	Capacity Prices Proposed Methodology ($/kW-Year)	Capacity Prices RPS Calculator ver 6.2 ($/kW-Year)
2016	$ 35.92	$ 33.00
2017	$ 44.33	$ 33.00
2018	$ 52.74	$ 33.00
2019	$ 61.16	$ 33.00
2020	$ 69.57	$ 33.00
2021	$ 77.99	$ 33.00
2022	$ 86.40	$ 33.00
2023	$ 94.81	$ 33.00
2024	$ 103.23	$ 33.00
2025	$ 111.64	$ 33.00
2026	$ 120.05	$ 33.00
2027	$ 128.47	$ 33.00
2028	$ 126.68	$ 33.00
2029	$ 126.15	$ 33.00
2030	$ 126.40	$ 33.00

V.

CONCLUSION

The IOUs submit this Joint Proposal in compliance with Ordering Paragraph 4 of the Ruling. This Joint Proposal provides a publicly available capacity price curve for benchmarking purposes. While other capacity price forecasts in other curves (e.g., the RPS Calculator and the IOUs' individual proprietary curves) will differ from the proposed benchmarks in this curve, the underlying methodology is the same: a short-run capacity price that transitions to a long-run capacity price. The method for this transition (e.g., a straight line or a step function) may vary, and the inputs impact exactly when this transition to a RBY occurs, but the underlying approach remains consistent. This illustrative capacity price curve can serve as a useful, publicly-available benchmark for comparison against these other capacity curves.

Respectfully submitted,

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September 8, 2016

VERIFICATION

I, Janos Kakuk, am a Manager in the Regulatory Affairs Organization of Southern California Edison Company and am authorized to make this verification on its behalf. I have read the foregoing **JOINT PROPOSAL OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E)**. I am informed and believe that the matters stated in the foregoing pleading are true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this **8th day of September, 2016**, at Rosemead, California.

/s/ Janos Kakuk
By: Janos Kakuk

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